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From: Brent Clayton RIII
To: OE Dixon-Herrity, Jennifer; Frye, Timothy; OEMAIL
Date: Thu, Apr 25, 2002 5:55 PM
Subject: Pt. Beach SERP package for 5/2?
Place: OEMAIL

Tim, I know Ken spoke with you earlier about trying to schedule this SERP for 5/2. (He left for the day before I heard your response.) Attached is the package. I am also faxing a one-line diagram (one page) to Jennifer. If you'd like me to fax it to you also, send me your fax number.

The SRA, Sonia Burgess, is unavailable until Monday, but I'm sure that she will be willing to address any questions from the HQ SRAs next week.

In order to give the risk analysts as much time as possible to review the package, I am forwarding it prior to EICS' review of the enforcement aspects. We'll do that tomorrow and provide any necessary changes.

---Brent

CC: Grant, Geoffrey; Krohn, Paul; Lambert, Kenneth; Lanksbury, Roger

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SDP/ENFORCEMENT PANEL WORKSHEET

EA-02-_____
Date of Panel: May 2, 2002
Licensee: Nuclear Management Company, LLC
Facility/Location: Point Beach Unit 2
License Type (non-reactor):
Docket No: 50-000301
License No: DPR-27
Inspection Report No: IR 50-266/02-05; 50-301/02-05
Date of Exit Meeting:
Panel Chairman (SES Sponsor): Geoff Grant
Responsible Branch Chief/Lead Inspector: Roger Lanksbury / Paul Krohn
Enforcement Representative: Ken Lambert
Other regional attendees: Sonia Burgess, SRA

1. Brief Summary of Issues/Potential Violations:

On February 20, 2002, at 1:00 a.m., the Unit 2 2P-15B SI pump was started as part of a monthly preventive maintenance bearing lubrication activity. The control room operators noted that when the pump was started, motor current increased normally, but then decayed to less than 10 amps. The normal SI pump running current was 30 amps. Additionally, the pump developed no discharge pressure. The auxiliary operator stationed locally in the vicinity of the SI pump noted a loud noise near the end of the pump coastdown, observed excessive seal leakage, and reported the presence of an acrid smell to the control room. The Duty Shift Superintendent arrived in the pump area shortly thereafter, observed the excessive seal leakage, and perceived the acrid smell. Through follow-up discussion and observation it was concluded that the acrid smell was emanating from the inboard pump seal area. The Duty Shift Superintendent directed the isolation of the pump to secure the excessive seal leakage. The 2P-15B SI pump was declared inoperable and TS Action Condition 3.5.2.A.1 entered at 1:00 a.m. on February 20, 2002. Technical Specification Action Condition 3.5.2.A.1 required an inoperable ECCS train to be restored to operable status within 72 hours or the affected Unit to be placed in Mode 3 (Hot Standby) within the following 6 hours and Mode 4 (Hot Shutdown) within 12 hours.

Subsequent inspection of the pump revealed damage to the rotating element, the coupling and shaft keys between the pump and the motor, the pump internal wearing rings, and other components. Licensee investigation revealed that the cause of the equipment damage was pump gas binding as the result of back-leakage of nitrogen-saturated fluid from the SI 'A' accumulator through at least two check valves, 2SI-845E, "Unit 2 2P-15B SI Pump To Reactor Coolant Loop 'A' Cold Leg SI Check Valve" and 2SI-889B, "Unit 2 2P-15B SI Pump Discharge Check Valve," to the 2P-15B pump discharge side. When the nitrogen-saturated water pressure was reduced from the accumulator pressure (750 pounds per square inch gauge) to the SI pump suction pressure (~30 pounds per square inch gauge), the nitrogen came out of solution causing the 2P-15B gas binding. (See attached one line diagram)

The licensee proceeded with the repair of 2P-15B with the expectation that the pump would be repaired, tested, and returned to service prior to the expiration of 72 hour TS Action Statement 3.5.2.A.1. At approximately 2:00 p.m. on February 22, 2002, the licensee determined pump repairs and testing could not be completed before the expiration of the TS action statement. Accordingly, shutdown of Unit 2 began at 2:48 p.m. on February 22, 2002. Mode 3 was reached at 7:26 p.m. on February 22, and Mode 4 at 1:38 a.m. on February 23, 2002. During the time that the Unit 2 'B' ECCS train was inoperable, the 'A' ECCS train remained in standby service and was capable of performing the intended safety function.

The performance deficiency existed in that, on multiple occasions, the licensee failed to promptly identify and correct a significant condition adverse to quality regarding leakage from the 2T-34A safety injection accumulator. Specifically, on February 12, 2001, (CR 01-0454) and January 15, 2002, (AR 1862) licensed control room operators identified decreasing 2T-34A safety injection accumulator level trends but the license failed to determine the root cause of the leakage and prevent reoccurrence. In addition, NRC Information Notices 97-040 and 88-023, Supplements 1 through 5, provided at least six other corrective action program opportunities between 1989 and 1999 to cause the licensee to consider the effects of SI accumulator leakage on equipment operability. Failure of the licensee to critically evaluate and correct the cause of the accumulator leakage resulted in failure of the 2P-15B safety injection pump, due to gas binding caused by back-leakage of nitrogen-saturated water from the accumulator to the pump casing, on February 20, 2002, during monthly lubrication activities.

2. **Purpose of Panel:**

To reach consensus on the significance of the inspection finding as evaluated through the SDP and to determine the appropriate enforcement action, if any. The inspectors and SRA applied the benchmarked Point Beach Risk Informed Inspection Notebook (Revision 0, dated 11/29/2000) to the finding. The Phase 2 risk assessment characterized this finding as YELLOW; however, based on the benchmark visit the SI pump was identified as being 1 order of magnitude conservative. The licensee's analysis and a SPAR analysis also verifies that this issue, given the duration identified in the inspection, yields a WHITE finding. Based on the benchmarked results and the verification provided by the licensee's analysis and the SPAR analysis, the issue is being characterized as WHITE.

3. **Regional Recommended Enforcement Strategy:**
Issue a choice letter and close unresolved item in inspection report 50-301/2002-03 with

a potential WHITE finding. An inadequate corrective action violation (Appendix B, Criterion XVI), is proposed, stating that the licensee's corrective action program and operating experience assessment process failed to critically evaluate and correct a significant condition adverse to quality regarding leakage from a safety injection accumulator that had been identified in two licensed reactor operator condition reports (January 2002 and February 2001) and six NRC generic communications (1988 through 1999). Failure of the licensee to critically evaluate and correct the cause of the accumulator leakage resulted in failure of the 2P-15B safety injection pump, due to gas binding caused by back-leakage of nitrogen-saturated water from the accumulator to the pump casing, on February 20, 2002, during monthly lubrication activities. See the draft NOV attached (Attachment 2).

4. **Analysis of Significance/Root Cause:**

a. **Actual Consequence:** There were no actual consequences associated with this finding. There were no events during the time period that Unit 2 B SI pump was unavailable for accident mitigation.

b. **Potential Consequence(s):** The time used in the risk evaluation represents a loss of safety function of a single train of Unit 2 safety injection for greater than the TS allowed outage time. The Unit 2 'B' train of SI would have been unavailable if called upon for actual mitigation purposes. The Unit 2 'A' train of SI remained available if called upon for actual mitigation purposes.

Phase 2 SDP Risk Evaluation:

Pertinent Time Line

Below is a time line of pertinent information regarding the Unit 2 B SI pump.

Date/Time	Train 'A' SI	Train 'B' SI	Comment
12/29/01 0242		X	Successful completion of quarterly TS surveillance. No abnormalities noted.
12/29/01 2216	X		'A' SI pump used to refill Unit 2 'A' SI accumulator
12/31/01 1940	X		'A' SI pump used to refill Unit 2 'A' SI accumulator
1/4/02 0109	X		'A' SI pump used to refill Unit 2 'A' SI accumulator
1/7/02 0432	X		'A' SI pump used to refill Unit 2 'A' SI accumulator
1/9/02 2157	X		'A' SI pump used to refill Unit 2 'A' SI accumulator
1/13/02 0209	X		'A' SI pump used to refill Unit 2 'A' SI accumulator

1/15/02			Licensed reactor operator writes Action Request 1862 identifying a large magnitude increase in Unit 2 'A' accumulator rate of level decrease. AR closed to WO for repair of fill valve.
1/16/02 2054	X		'A' SI pump used to refill Unit 2 'A' SI accumulator
1/19/02 1555	X		'A' SI pump used to refill Unit 2 'A' SI accumulator
1/24/02 0333		X	Unit 2 'B' SI pump run for monthly bearing lubrication preventative maintenance. No abnormalities noted.
1/24/02 0320	X		'A' SI pump used to refill Unit 2 'A' SI accumulator
1/26/02 1736	X		'A' SI pump used to refill Unit 2 'A' SI accumulator
1/30/02 1746	X		'A' SI pump used to refill Unit 2 'A' SI accumulator
2/4/02 0858	X		'A' SI pump used to refill Unit 2 'A' SI accumulator
2/9/02 2019	X		'A' SI pump used to refill Unit 2 'A' SI accumulator
2/14/02 0748	X		'A' SI pump used to refill Unit 2 'A' SI accumulator
2/17/02 2351	X		'A' SI pump used to refill Unit 2 'A' SI accumulator
2/20/02 0100		X	Unit 2 'B' SI pump started for monthly bearing lubrication preventative maintenance run. Pump fails within seconds of starting.

Surveillance Test and Monthly Lubrication Run Characteristics

Test	Characteristic
Monthly Run	Brief run for bearing lubrication purposes. Vendor recommended OE for motor sleeve bearing configuration to minimize shaft chemical etching and remove oxidation deposits resulting from moisture absorption into the oil film. Control room operators run the SI pump until normal running current is developed and the local operator reports no abnormalities. Typically, the SI pump is run for less than 30 seconds.
Quarterly Surveillance	Required by TS surveillance requirement 3.5.2.2 in accordance with Inservice Testing Program specified in Section XI of the ASME Boiler and Pressure Vessel Code and Applicable Addenda. Required to be performed at least once per 92 days. Functional test of the SI pump includes flow and differential pressure measurements at 200, 400, 600, and 800 gpm. Design flow rate of SI pump is 700 gpm.

Phase 2 SDP Risk Evaluation:
The inspectors and SRA evaluated the risk significance of the inspection finding in terms of the contribution from internal, external, and LERF events. Consistent with the guidance for the Significance Determination Process (SDP), the change in core damage frequency (ΔCDF) was evaluated considering the Unit 2 B SI pump unavailable from one half the time period from the last successful demonstration of pump performance to the time of pump failure. External initiating events, seismic, fire, and tornado/high winds were individually considered.

Based on the Point Beach SDP Phase 2 worksheets, which have been benchmarked, the dominant accident sequence occurs with a medium break LOCA (MLOCA). The licensee submitted an LER on April 18, 2002 , documenting the Unit 2 TS required shutdown on February 22, 2002. The LER focused on the TS required shutdown and did not offer any new information concerning risk arguments as to when the SI pump became unavailable or details of the root cause evaluation. The following summarizes the inspector's Phase 2 risk assessment.

Phase 2 Evaluation

Internal Initiating Events

Assumptions

1. The inspectors did not consider the ability to recover the 2P-15B SI pump following the start on February 20, 2002, since the pump seized, the shaft keys between the motor and pump were sheared, and the pump coupling was damaged. The failure on February 20 occurred within seconds of the pump start.

2. Based on the licensee's PRA, the 2P-15B SI pump had a risk achievement worth (RAW) value of 1.61 and the plant had a baseline core damage frequency (CDF) of 4.46E-5 per reactor year.

3. The last successful quarterly surveillance test of 2P-15 was performed on December 29, 2001, in accordance with inservice test procedure IT 02, "High Head Safety Injection Pumps and Valves (Quarterly) Unit 2," Revision 48. During this inservice test, 2P-15B was operated at 200, 400, 600, and 800 gallons per minute (gpm) discharge flow, met all acceptance criteria, and exhibited no abnormalities. Subsequent to the inservice test, a short monthly run of 2P-15B for bearing lubrication preventative maintenance was performed on January 24, 2002. No abnormalities were noted during the 2P-15B January 24 run.

   Since the failure of the 2P-15B SI pump occurred within seconds of the pump start on February 20, 2002, the inspectors considered the last successful demonstration of the 2P-15B SI pump to have occurred on January 24, 2002, at 3:33 a.m. when the pump had run for approximately 30 seconds.

4. The inspectors correlated Unit 2 A accumulator level and pressure history with 2P-15B line volumes. Using direct mass balance methods, the inspectors determined that sufficient accumulator leakage existed between December 29, 2001, and January 24, 2002 to fill the line volume between the accumulator check valve, 2SI-845E, and the 2P-15B SI pump discharge check valve, 2SI-889B, with nitrogen-saturated water by a factor of four. In addition, the inspectors determined that sufficient accumulator leakage existed between January 24, 2002, and February 20, 2002, to fill the 2P-15B SI pump casing with nitrogen gas by a factor of 2.5. Direct mass balance methods predicted SI pump failure due to gas binding within 24 to 96 hours following the last pump run with the leak rates historically observed. The inspectors noted that no failures had occurred during the 13 month interval prior to February 20, 2002, even though 2P-15B was operated once per approximately 30 days. This 2P-15B performance history indicated the presence of other difficult-to-quantify variables including;

- leakage of nitrogen-saturated gas from SI pump mechanical seals
- diffusion of nitrogen gas through SI system valve packing to atmosphere
- the presence of parallel leakage paths from the 2T-34A accumulator back to the 2P-15B pump casing.

Licensee performance of Point Beach Test Procedure 113, "2T-34A SI Accumulator Leakage Test," on March 29, 2002, and OI-171, "T-34A/B Safety Injection Accumulator leakage troubleshooting," on April 5, 2002 confirmed that parallel leakage paths between the accumulator and the pump casing existed.

The inspectors also reviewed integrated 2T-34A accumulator leakage data between 2P-15B pump runs for the time period between March 2001 and February 2002. When failure of 2P-15B occurred on February 20, 2002, approximately 700 gallons of nitrogen-saturated water had leaked from the 2T-34A accumulator. Because of the unpredictable and variable behaviors of the past leakage data, valve packing leakage, pump mechanical seal leakage, and parallel leakage paths, the inspectors concluded that a threshold above which 2P-15B SI pump failure was certain to have occurred could not be established and a time period at which the 2P-15B SI pump had become inoperable could not reasonably be determined. Therefore, in accordance with Inspection Manual Chapter 0609, "Significance Determination Process," Attachment A, Step 1.1, Revision dated March 18, 2002, an exposure time of one-half of the time period since the last successful demonstration of the 2P-15B pump was used.

In this case, the exposure time for risk analysis purposes existed for one-half the time period from January 24, 2002, at 3:33 a.m. to February 20, 2002, at 1:00 a.m. (13.95 days) plus the time to reach a condition in which the SI pump was no longer required to be operable (Mode 4). Unit 2 reached Mode 4 at 1:35 a.m. on February 23, 2002, (3.02 days), providing a total exposure time of (13.95 + 3.02 = 16.97) or 17.0 days.

5. Concerns for voiding of common ECCS piping were eliminated due to: (1) elevation differences between the SI pump casings and other ECCS pump common suction lines (the SI pump casings were 3.5 ft above the common ECCS suction line), and (2) the A train SI pumps had been run frequently to refill SI accumulators and had effectively swept any nitrogen-saturated water or gas voids back into the accumulators (the A train pumps exhibited no symptoms of gas binding).

Work Sheet Results
Using Table 1, "Categories of Initiating Events for Point Beach Nuclear Plant," from the "Risk-Informed Inspection Notebook for Point Beach Nuclear Plant Unit 1 and 2," the exposure time for the degraded condition (gas binding of the SI pump) was considered to be between 3 and 30 days. Table 2, "Initiators and System Dependency for Point Beach Units 1 and 2," determined that loss of one SI pump affected the following initiating events;

1. TRANS = Transients (Reactor Trip)
2. TPCS = Transients Without Power Conversion System
3. LDC1 = Loss of Single 125 VDC Bus 01
4. LDC2 = Loss of Single 125 VDC Bus 02
5. SLOCA = Small LOCA
6. SORV = Stuck Open PORV
7. MLOCA =Medium LOCA
8. LOOP = Loss of Offsite Power
9. LEAC = LOOP Plus Loss of Gas Turbine with 1 EAC Available
10. SGTR = Steam Generator tube Rupture
11. MSLB = Main Steam Line Break

Each initiating event and relevant accident sequence is provided below.

1. Transients (Reactor Trip)
TRANS = Row I. Estimated Likelihood Rating based on 17 days condition existed = "2". Applicable sequences:

#1 TRANS(2) + PCS (3) + AFW (4) + HPR (2) = 11 (10^{-11}) = GREEN
#3 TRANS(2) + PCS(3) + AFW (4) + EIHP (2) = 11 (10^{-11}) = GREEN

2. Transients Without Power Conversion System
TPCS = Row I. Estimated Likelihood Rating based on 17 days condition existed = "2". Applicable sequences:

#1 TPCS(2) + AFW(4) + HPR(2) = 8 (10^{-8}) = GREEN
#3 TPCS(2) + AFW(4) + EIHP(2) = 8 (10^{-8}) = GREEN

3. LDC1 = Loss of Single 125 VDC Bus 01
LDC1 = Row III. Estimated Likelihood Rating based on 17 days condition

existed = "4". Assumption is that single loss of 125 VDC occurs on 'A' train of engineering safeguards equipment. Applicable sequences:

#1 LDC1(4) + AFW(3) + HPR(0) = 7 (10^{-7}) = GREEN
#3 LDC1(4) + AFW(3) + EIHP(0) = 7 (10^{-7}) = GREEN

4. <u>LDC2 = Loss of Single 125 VDC Bus 02</u>
LDC2 = Row III. Estimated Likelihood Rating based on 17 days condition existed = "4". Assumption is that single loss of 125 VDC occurs on 'B' train of engineering safeguards equipment. Applicable sequences:

#1 LDC2(4) + AFW(3) + MFW(2) + HPR(2) = 11 (10^{-11}) = GREEN
#3 LDC2(4) + AFW(3) + MFW(2) + EIHP(2) = 11 (10^{-11}) = GREEN

5. <u>SLOCA = Small LOCA</u>
SLOCA = Row III. Estimated Likelihood Rating based on 17 days condition existed = "4". Applicable sequences:

#2 SLOCA(4) + RCSDEP(2) + HPR(2) = 8 (10^{-8}) = GREEN
#3 SLOCA(4) + AFW(4) + HPR(2) = 10 (10^{-10}) = GREEN
#5 SLOCA(4) + EIHP(2) + LPI(3) = 9 (10^{-9}) = GREEN
#6 SLOCA(4) + EIHP(2) + ACC(3) = 9 (10^{-9}) = GREEN
#7 SLOCA(4) + EIHP(2) + RCSDEP(2) = 8 (10^{-8}) = GREEN
#8 SLOCA(4) + EIHP(2) + AFW(4) = 10 (10^{-10}) = GREEN

6. <u>SORV = Stuck Open PORV</u>
SLOCA = Row III. Estimated Likelihood Rating based on 17 days condition existed = "4". Applicable sequences:

#2 SORV(4) + BLK(1) + RCSDEP(2) + HPR(2)= 9 (10^{-9}) = GREEN
#3 SORV(4) + BLK(1) + AFW(4) + HPR(2) = 11 (10^{-11}) = GREEN
#6 SORV(4) + BLK(1) + EIHP(2) + LPI(3) = 10 (10^{-10}) = GREEN
#7 SORV(4) + BLK(1) + EIHP(2) + ACC(3) = 10 (10^{-10}) = GREEN
#8 SORV(4) + BLK(1) + EIHP(2) + RCSDEP(2) = 9 (10^{-9}) = GREEN
#9 SORV(4) + BLK(1) + EIHP(2) + AFW(4) = 11 (10^{-11}) = GREEN

7. <u>MLOCA = Medium LOCA</u>
MLOCA = Row III. Estimated Likelihood Rating based on 17 days condition existed = "4". Applicable sequences:

#1 MLOCA(4) + HPR(2) = 6 (10^{-6}) = WHITE
#3 MLOCA(4) + EIHP(2) + LPR(2) = 8 (10^{-8}) = GREEN
#4 MLOCA(4) + EIHP(2) + LPI(3) = 9 (10^{-9}) = GREEN
#5 MLOCA(4) + EIHP(2) + DEP(2) = 8 (10^{-8}) = GREEN

#6 MLOCA(4) + EIHP(2) + AFW(4) = 10 (10^{-10}) = GREEN

8. LOOP = Loss of Offsite Power
TPCS = Row II. Estimated Likelihood Rating based on 17 days condition existed = "3". Note that accident sequence #4 assumes AC Power is recovered. Applicable sequences:

#1 LOOP(3) + AFW(4) + HPR(2) = 9 (10^{-9}) = GREEN
#3 LOOP(3) + AFW(4) + EIHP(2) =9 (10^{-9}) = GREEN
#4 LOOP(3) + EAC(5) + TDAFW(1) + HPR(2) = 11 (10^{-11}) = GREEN
#5 LOOP(3) + EAC(5) + TDAFW(1) + MDAFW(3) + EIHP(2) =14 (10^{-14}) = GREEN

9. LEAC = Loss of Offsite Power Plus Loss of Gas Turbine With EAC Available
LEAC = Row V. Estimated Likelihood Rating based on 17 days condition existed = "6". Assumption is that emergency AC power is not available on the 'A' engineered safeguards feature train. Applicable sequences:

#1 LEAC(6) + AFW(3) + HPR(0) = 9 (10^{-9}) = GREEN
#3 LEAC(6) + AFW(3) + EIHP(0) =9 (10^{-9}) = GREEN
#5 LEAC(6) + SORV(2) + RCSDEP(2) + HPR(0) = 10 (10^{-10}) = GREEN
#6 LEAC(6) + SORV(2) + EIHP(0) =8 (10^{-8}) = GREEN

10. SGTR = Steam Generator Tube Rupture
SGTR = Row III. Estimated Likelihood Rating based on 17 days condition existed = "4". Assumption is that emergency AC power is not available on the 'A' engineered safeguards feature train. Applicable sequences:

#5 SGTR(4) + AFW(4) + EIHP(2) = 10 (10^{-10}) = GREEN

11. MSLB = Main Steam Line Break Accident
MSLB = Row III. Estimated Likelihood Rating based on 17 days condition existed = "4". Applicable sequences:

#1 MSLB(4) + AFW(4) + HPR(2) = 10 (10^{-10}) = GREEN
#3 MSLB(4) + ISOL(2) + HPR(2) = 8 (10^{-8}) = GREEN
#5 MSLB(4) + EIHP(2) + AFW(4) = 10 (10^{-10}) = GREEN
#6 MSLB(4) + EIHP(2) + ISOL(2) = 8 (10^{-8}) = GREEN

Application of SDP Counting Rule
Based on the counting rules of the SDP discussed in Inspection Manual Chapter 0609, Appendix A, Attachment 2, paragraph 3.2; every 3 affected accident sequences that have the same order of magnitude of risk, as determined by the addition of the initiating event likelihood and the remaining mitigation capability, constitute one equivalent sequence which is more risk significant by one order of magnitude. This rule is applied

in a cascading fashion.

The results of the counting rule yields a YELLOW finding; however, based on the benchmark visit (conducted July 2001) the SI pump was identified as being 1 order of magnitude conservative. Based on this the risk significance of this issue is more appropriately characterized as WHITE. This WHITE risk characterization is further verified through NRC SPAR analysis and a licensee's analysis as discussed below.

Consideration of other risk tools to confirm SDP notebook benchmarking results

RAW calculation Based on the licensee's PRA, the "B" SI pump had a risk achievement worth (RAW) value of 1.61 and the plant has a baseline core damage frequency (CDF) of 4.46E-5 per reactor year.

$$\Delta CDF \approx [(RAW \times CDF) - CDF] \times \text{duration (years)}$$
$$= [(1.61) \times 4.46E\text{-}5) - 4.46E\text{-}5] \times 408 \text{ hrs}/8760 \text{ hrs}$$
$$= 1.3E\text{-}6$$

SPAR Using the same pump unavailability duration the CCDP = 4.1E-6.

External Events

The regional SRA determined that the change in CDF due to external events was small; much less than one order of magnitude.

1. Fire - The Point Beach fire-induced CDF estimate is approximately 5.1E-5/year based on the IPEEE submittal; however, the licensee completed an IPEE update that determined the fire CDF contribution is 1.25E-5/yr. This reduction was primarily due to adding two diesel generators and moving the Train B 4kV buses to the new EDG building in the mid-1990s. Fire was not found to result in a significant contribution to ΔCDF because the SI system is not involved in the dominate sequences. The dominate sequences use alternate shutdown, which does not credit the SI system.

2. Seismic - The Point Beach seismic-induced CDF estimate is approximately 1.3E-5/year based on the IPEE submittal. The SI system is used in transients following a failure of PORVs to re-close and in seismically-induced small LOCAs. The licensee and SRA reviewed a total of 72 sequences involving SI failure and the impact of pump 2P15B being unavailable for 17 days. The ΔCDF was much less than 2E-7. Also, the risk analyst evaluated the external event contribution due to seismic event utilizing the methodology from NUREG/CR-6544, Methodology for Analyzing Precursors to Earthquake-Initiated and Fire-Initiated Accident Sequences. The analyst compared the risk contribution from a median earthquake on the LOOP seismic fragility curve that causes a LOOP event against a randomly occurring LOOP. The risk due to a seismic LOOP was found to be several orders of magnitude lower than the randomly occurring LOOP.

This is a result of the seismic initiating event frequency (based on LLNL Hazard curve) of 2E-5/yr verses a random LOOP initiating event frequency of 7.1E-3/yr (from the licensee's updated PRA). Overall, seismic events were not found to result in a significant contribution to ΔCDF.

3. High Winds, Floods, and other External Events (HFO) - The IPEEE study concluded that the HFO had an insignificant contribution to the CDF. High winds were considered to have an insignificant impact because SI was not credited. Internal flooding also had minimal impact because the important scenarios already involved an actual or assumed loss of SI.

   Considering the information available in the IPEE, SER, and review of the licensee's analysis, accounting for external events are unlikely to change the ΔCDF 1 order of magnitude. The finding is considered WHITE when considering internal and external events.

Potential Risk Contribution due to LERF

In large dry PWR containments, only a subset of core damage accidents can lead to large, unmitigated releases from containment that have the potential to cause prompt fatalities prior to population evacuation. Core damage sequences of particular concern for large dry PWR containments are ISLOCA and SGTR sequences. The SGTR accident was an initiating event sequences associated with this finding (one 1E-10 sequence); however, it was not a dominant sequence in the internal event assessment. The licensee's evaluation of ΔLERF over the 17 day period was approximately 2.44E-7. Considering these factors, the risk analyst determined that the change in LERF did not warrant an increase in the risk significance characterization.

Conclusion

The inspector and analyst's risk evaluation finds the increase in CDF due to internal events to be WHITE and the risk impact of the inspection finding due to external initiating events to be very small (less than 1 order of magnitude). The potential risk contribution to LERF due to the SI pump unavailability was determined to be negligible. The analyst concludes the risk significance of the inspection finding based on the change in CDF due to internal, external, and LERF considerations to be WHITE. A WHITE finding represents a finding of low to moderate safety significance.

c. **Potential for Impacting Regulatory Process:** None

d. **Willful Aspects:** None

d. **Root Cause(s):** Inadequate corrective action violation (Appendix B, Criterion XVI), is proposed, stating that the licensee's corrective action program and operating experience assessment process failed to critically evaluate and correct a significant condition adverse to quality identified in two licensed reactor operator condition reports (January 2002 and February 2001) and six NRC generic communications (1988 through April 1999).

The licensee conducted a root cause evaluation and concluded that;

- the licensee organization did not recognize an adverse accumulator trend prior to the actual event that resulted in gas binding of the Unit 2 B SI pump.
- standards and expectations were not effective for adequate risk assessment to ensure appropriate work prioritization
- a process for work priority determination based on short and long-term risk assessment of equipment issues did not exist at PBNP.

Contributing causes included:

- routine accumulator refilling promoted the acceptance of periodic accumulator refills as a routine operational evolution
- Back-leakage through multiple check valves was consistently deemed an unlikely occurrence at PBNP. The frequent identification of the accumulator fill and drain valves excessive leakage during troubleshooting efforts resulted in the Operations and Engineering organizations being desensitized to the possibility of other leakage pathways.
- Personnel turnover and position reductions resulted in a lack of continuity and adversely impacted operating experience (OE) evaluation and corrective action completion timeliness.

5. **Apparent Severity Level(s)/Color and Basis:** Violation characterized as having low to moderate safety significance (WHITE).

6. **Application of Enforcement Policy.** These items are generally not applicable for SDP cases; however, pertinent information is included below:

   a. **Enforcement/Performance History:** Not applicable.

   b. **Is Credit Warranted for Identification? Explain:** No, self-revealing failure of SI pump occurred during monthly preventative maintenance bearing lubrication activities.

   c. **Is Credit Warranted for Corrective Actions? Explain:** Corrective actions credit is not warranted because the licensee did not correct the root cause of the problem (gas binding of the Unit 2 B SI pump caused by back-leakage of nitrogen-saturated water from a safety injection accumulator) prior to the SI pump failure on February 20, 2002.

   d. **Should Discretion Be Exercised to Mitigate or Escalate Sanction?**

No.

7. Is action being considered against individuals? No.

8. Non-Routine Issues/Additional Information/Relevant Precedent/Lessons Learned: None.

Attachments:
1. NRC inspection report 50-266/02-05; 50-301/02-05, Sections 1R15.1 and 4AO2
2. Draft Violation
3. Phase 1 SDP Screening Worksheets
4. Point Beach Phase 2 SDP worksheets for TRANS, TPCS, LDC1, LDC2, SLOCA, SORV, MLOCA, LOOP, LEAC, SGTR, MSLB
5. Counting rule worksheet

Attachment 1: NRC Inspection Report 50-266/02-05; 50-301/02-05, Sections 1R15.1 and 4AO2

1R15 Operability Evaluations (71111.15)

.1 2P-15B SI Pump Failure Due to Gas Binding During Monthly Lubrication Run

a. Inspection Scope

The inspectors reviewed the circumstances surrounding a self-revealing failure of the 2P-15B Unit 2 SI pump on February 20, 2002. During the subsequent SI pump repair and replacement activities, the inspectors verified compliance with TS action condition statements; observed pump disassembly and reassembly; inspected failed parts; reviewed post-maintenance testing activities; and reviewed Final Safety Analysis Report (FSAR) design requirements. The inspectors reviewed Operability Determination (OBD) 000011, "Gas Binding of SI Pumps," to verify that the licensee had considered the potential effects of gas binding on;

- Unacceptable water hammers due to the rapid refilling of voided SI injection lines upon pump start
- Gas migration to other piping that may have rendered adjacent emergency core cooling system (ECCS) equipment sharing common suction piping inoperable
- Accident analyses due to a delay in injecting water into the reactor core as a result of having voided volumes in the SI pump discharge lines
- Various leaking (or failed open) valves in the system
- Flow and pressure instrument sensing lines
- Pressure-locking SI system valves during pressure transients
- Load amplification due to the constructive combination of reflected shock waves in partially voided SI injection lines.

The inspectors evaluated the OBD to verify that the venting locations, frequency, and instructions given to auxiliary operators for the conduct of venting were conservative and maintained SI pump operability. The inspectors reviewed SI and RHR pump suction and discharge piping isometric drawings to determine available venting points, the creation and effect of loop-seals for unventable portions of the injection line, and the extent to which voided gas volumes could have migrated back towards other ECCS pumps. The inspectors interviewed selected engineering personnel and reviewed pump internal drawings to determine the effects of varying pump casing gas volumes on SI pump operability. The inspectors reviewed the impact of 2SI-845E, "Unit 2 2P-15B SI Pump To Reactor Coolant Loop 'A' Cold Leg SI Check Valve," back-leakage on TS 3.4.14 RCS pressure insolation valve leak rate requirements. The inspectors also reviewed the licensee's troubleshooting plan to identify the leakage path from the Unit 2 'A' SI accumulator, 2T-34A, back to the 2P-15B SI pump casing and future check valve repair plans.

The inspectors reviewed Operating Instruction (OI) 163, "SI, RHR, and CS [Containment Spray] Pump Runs," Revision 1, to determine whether monthly SI pump runs for preventative maintenance bearing lubrication activities constituted preconditioning for TS required quarterly surveillance tests. The inspectors applied the results of OBD 000011 to both Units 1 and 2 to verify that the licensee had considered the full effects of accumulator back leakage on all ECCS equipment.

The inspectors interviewed selected engineering personnel and correlated Unit 2 'A' SI accumulator level and pressure history, 2P-15B SI pump injection line volumes, and nitrogen solubility data to determine when the 2P-15B SI pump had become inoperable. Finally, the inspectors considered previous licensee operating experience (OE) and corrective action program opportunities to have prevented failure of the 2P-15B SI pump.

b. Findings

Self-Revealing Condition

On February 20, 2002, at 1:00 a.m., the 2P-15B SI pump was started in accordance with OI-163 as part of a monthly preventative maintenance bearing lubrication activity. The control room operators noted that when the pump was started, motor current increased normally, but then decayed to less than 10 amps. The normal SI pump running current was 30 amps. Additionally, the pump developed no discharge pressure. The auxiliary operator stationed locally in the vicinity of the SI pump noted a loud noise near the end of the pump coastdown, observed excessive seal leakage, and reported the presence of an acrid smell to the control room. The Duty Shift Superintendent arrived in the pump area shortly thereafter, observed the excessive seal leakage, and perceived the acrid smell. Through follow-up discussion and observation it was concluded that the acrid smell was emanating from the inboard pump seal area. The Duty Shift Superintendent directed the isolation of the pump to secure the excessive seal leakage. The 2P-15B SI pump was declared inoperable and TS Action Condition 3.5.2.A.1 entered at 1:00 a.m. on February 20, 2002. Technical Specification Action Condition 3.5.2.A.1 required an inoperable ECCS train to be restored to operable status within 72 hours or the affected Unit to be placed in Mode 3 (Hot Standby) within the following 6 hours and Mode 4 (Hot Shutdown) within 12 hours.

Subsequent inspection of the pump revealed damage to the rotating element, the coupling and shaft keys between the pump and the motor, the pump internal wearing rings, and other components. Licensee investigation revealed that the cause of the equipment damage was pump gas binding as the result of back-leakage of nitrogen-saturated fluid from the SI 'A' accumulator through at least two check valves, 2SI-845E, "Unit 2 2P-15B SI Pump To Reactor Coolant Loop 'A' Cold Leg SI Check Valve" and 2SI-889B, "Unit 2 2P-15B SI Pump Discharge Check Valve," to the 2P-15B pump discharge side. When the nitrogen-saturated water pressure was reduced from the accumulator pressure (750 pounds per square inch gauge) to the SI pump suction pressure (~30 pounds per square inch gauge), the nitrogen came out of solution causing the 2P-15B gas binding.

The licensee proceeded with the repair of 2P-15B with the expectation that the pump would be repaired, tested, and returned to service prior to the expiration of 72 hour TS Action Statement 3.5.2.A.1. At approximately 2:00 p.m. on February 22, 2002, the licensee determined pump repairs and testing could not be completed before the expiration of the TS action statement. Accordingly, shutdown of Unit 2 began at 2:48 p.m. on February 22, 2002. Mode 3 was reached at 7:26 p.m. on February 22, and Mode 4 at 1:38 a.m. on February 23, 2002. Operator performance during the Unit 2 forced shutdown was reviewed in Section 1R14.1 of this report. During the time that the Unit 2 'B' ECCS train was inoperable, the 'A' ECCS train remained in standby service and was capable of performing the intended safety function.

Operability of 2P-15B SI and Other ECCS Pumps

The inspectors reviewed and found acceptable the licensee's OBD conclusion that venting the SI lines at least every five days was sufficient to ensure continued operability of the Units 1 and 2 SI pumps. The frequency was based on observed accumulator leakage history and would increase proportionately if accumulator leakage rates increased. The inspectors also concluded that the Units 1 and 2 'A' train SI pumps had remained operable since these pumps had been run frequently to refill SI accumulators and had effectively swept any nitrogen-saturated water or gas voids back into the accumulators each time the pumps were run. The Unit 1 'B' train SI pump was considered to have been operable based on the time of the last successful run and the observed accumulator level trends which indicated that insufficient leakage had occurred to fill the Unit 1 'B' SI pump with nitrogen-saturated water leading to gas binding failure as had occurred with 2P-15B.

Concerns for voiding of common ECCS piping were eliminated due to elevation differences between the SI pump casings and other ECCS pump common suction lines (the SI pump casings were 3.5 feet above the common ECCS suction line), the fact that the adjacent pump (2P-15A) exhibited no symptoms of gas binding, and the likelihood that at least a portion of the evolved gas had been venting through the 2P-15B pump shaft seals. The inspectors also reviewed the effect of the SI flow delay during design transients to the reactor core caused by partially voided injection lines and determined that the limiting parameter of concern, nuclear fuel peak centerline temperature, remained bounded by existing accident analyses. A review of the gas voiding on water hammer, shock amplification loadings, valve pressure locking, and instrumentation effects raised no other operability concerns.

Analysis

The inspectors assessed this issue using the Significance Determination Process. The inspectors concluded that the failure of the 2P-15B SI pump had a credible impact on safety since the 2P-15B SI pump was credited for mitigating the consequences of design basis and risk significant transients including: reactor trips, transients without the secondary power conversion system, loss of a single 125 volt direct current safeguards bus, small break LOCAs, stuck open pressurizer power-operated relief valves, medium break LOCAs, loss of offsite power, loss of offsite power plus loss of the gas turbine with one emergency alternating current power source unavailable, steam generator tube rupture, and main steam line break accidents. Consequently, the failure of the 2P-15B SI pump had a credible impact on safety and was associated with the mitigating systems cornerstone.

Using the Significance Determination Process Phase 1 Screening Worksheet for the Mitigating Systems Cornerstone, the inspectors concluded that failure of the 2P-15B SI pump was considered to be at least of very low safety significance (Green). Pending further inspector and Region III review of the regulatory and risk aspects of the 2P-15B SI pump failure, the safety significance of the finding is To Be Determined and this issue will be considered an Unresolved Item (URI). Problem identification and resolution aspects of the 2P-15B safety injection pump failure are discussed in Section 4OA2 of this report.

4OA2 Identification and Resolution of Problems

.1 2P-15B SI Pump Failure Due to Gas Binding During Monthly Lubrication Run

a. Inspection Scope

The inspectors reviewed the corrective action and operating experience program history surrounding the self-revealing failure of the 2P-15B Unit 2 SI pump due to gas binding on February 20, 2002. Specifically, the inspectors reviewed the corrective action and operating experience history provided by the licensee in Root Cause Evaluation 000044, "Unit 2 Safety Injection Pump "Damaged" During Routine Preventative Maintenance," to determine the causes of the 2P-15B failure. A description of the circumstances and operability considerations associated with the safety injection pump failure are provided in Section 1R15.1 of this report.

Findings

The licensee initiated a root cause evaluation team on February 23, 2002, to identify why the safety injection pump failure had occurred and to determine corrective actions to prevent reoccurrence. The licensee's evaluation identified that the Point Beach organization had not properly responded to adverse SI accumulator trends that increased the potential for gas binding of the SI pumps. The licensee also concluded that the operating experience program had not been effective in ensuring timely implementation of corrective actions from previous lessons learned.

The inspectors reviewed the corrective action and operating experience history collected by the root cause evaluation team and noted at least two specific opportunities to have identified the Unit 2, 'A' accumulator, 2T-34, adverse leakage trend prior to the 2P-15B SI pump failure.

- Action Request 1862, "Excessive Leakage of 2T-34A SI Accumulator," was initiated on January 15, 2002, by a licensed reactor operator who identified an adverse trend in the rate of decrease of the Unit 2 'A' accumulator level. The licensed reactor operator recommended further evaluation to pinpoint a leakage path since his analysis efforts had been inconclusive. The licensed reactor operator attached a graph of Unit 2 'A' accumulator level history to the AR which showed a marked change in the 2T-34A accumulator leakage rate following performance of the last quarterly 2P-15B TS surveillance test on December 29, 2001. Prior to December 29, 2001, the Unit 2 'A' accumulator had been lowering at a rate of approximately 1 percent per day. However, following the quarterly surveillance test and fill of the accumulator on December 29, 2001, the accumulator began lowering at an average rate of 4 to 5 percent per day.

Action Request 1862 was reviewed by plant manager's staff on January 16, 2002, and closed with no further action, to an open WO to investigate leakage through the accumulator fill valve.

- Condition Report 01-0454, "Unit 2 'A' Safety Injection SI Accumulator Level," was initiated on February 12, 2001, by a different licensed reactor operator who identified that the Unit 2 'A' accumulator level was lowering slowly, requiring refilling numerous times per Operating Instruction OI-100, "Adjusting SI Accumulator Level and Pressure." Work order 9935625 was initiated to determine whether the accumulator drain valve, 2SI-844A, or the accumulator fill valve, 2SI-835A, was leaking. Results of WO 9935625 were inconclusive and CR 01-0454 was closed to WOs 9939167 and 9939168 to correct the drain and fill valve seat leakage during the next refueling outage. In closing CR 01-054, the system engineer noted that either both the drain and fill valves were leaking or another drain path existed. At the time of the 2P-15B SI pump failure, the WOs to repair the accumulator fill and drain valves had not yet been completed and remained open.

Several other Unit 1 and 2 corrective program opportunities had existed to cause the licensee to question accumulator leakage paths and the consequences of continued leakage on SI pump operability. Condition reports 97-1044, "Unit 1 SI Accumulator Stop Valves Leak By," CR 96-0908 "Unit 1 SI Accumulator Level Loss," CR 98-0171 "2SI-843B SI Accumulator First Off Isolation Valve Leaking," and CR 99-2717 identified various combinations of leaking accumulator drain, local sample isolation, and fill valves. Each CR was closed to a WO which repaired the leaking valves. Other corrective action program opportunities that had existed to cause the licensee to more thoroughly question potential accumulator leakage paths and the Unit 1 and 2 leakage consequences included;

- Condition Report 96-1789, "SI Accumulator (1T-34A) Level Decreasing," was initiated on December 17, 1996, and identified that the Unit 1 SI accumulator had been decreasing about 1 percent per day. The CR was closed to WO 94893 which, at the end of this inspection period, had not been traced to closure in the licensees work planning system.

- Condition Report 97-3942, "Unit 1 'A' SI Accumulator Lost 86.6 Gallons of Borated Water," was initiated on December 1, 1997, and identified that the leakage, following evaluation, was believed to be going through fill valve, 1SI-835A. The CR was closed to WO 9714938 which identified that the accumulator continued to leak even when the drain valve, 1SI-844A, was isolated. The CR indicated that because of the leakage investigation done, and other actions in place under CR 97-3932, the only additional action needed was the creation of a new item for engineering personnel to evaluate if the noted rate of level increase in the reactor coolant drain tank was acceptable. This action item had not been created when the CR was closed.

- Condition Report 98-1004, "SI Accumulator Level Decrease," was initiated on

March 11, 1998, and identified that the Unit 2 'A' accumulator was decreasing by approximately 3 percent per day. The initial recommendation was to close this CR to an open WO written to repair seat leakage on the 2T-34A accumulator outlet valve, 2SI-841A. At the request of the system engineer, however, the CR was re-opened to evaluate and track the issue of dissolved nitrogen coming out of solution once it had leaked by the accumulator isolation valve. Condition Report 98-1004 contained a September 1999 cross-reference to OE at another commercial pressurized water reactor which discussed gas binding of high-head SI pumps via back-leakage through check valves that isolate the RCS from the SI and RHR systems.

In addition, several industry OE opportunities had existed to alert the licensee to examine SI accumulator leakage paths and the potential SI pump operability consequences. Operating experience opportunities included:

- Information Notice (IN) 97-040, "Potential Nitrogen Accumulation Resulting From Back-Leakage From Safety Injection Tanks," was evaluated by the license in September 1997. As a result of the review, Operating Procedure OP-1A, "Cold Shutdown to Hot Shutdown," was revised to require venting of the high point of the accumulator discharge lines prior to startups.

- Information Notice 88-023, "Potential for Gas Binding of High-Pressure Safety Injection Pumps During a Loss-of-Coolant-Accident," Supplements 1 through 4, were evaluated between January 1989 and May 1993. These supplements focused on gas binding of the high head SI pump suction due to back-leakage from the RCS and RHR systems.

- Information Notice 88-023, "Potential for Gas Binding of High-Pressure Safety Injection Pumps During a Loss-of-Coolant-Accident," Supplement 5 and licensee OE document 9876, "4B HHSI [High-Head Safety Injection] Pump Gas Binding," were evaluated by the licensee in June 1999. During the evaluation the licensee concluded that previous OE responses on the gas binding subject were incomplete, not thorough, too narrowly focused, and that the potential for nitrogen accumulation in the SI piping from check valve or multiple valve leakage paths had not been addressed. This conclusion resulted in the generation of a single action item under IN 88-023 for the performance of an in-depth re-evaluation of the gas binding phenomena including re-evaluation of all prior documents on the gas binding issue. The inspectors noted that a CR concerning the lack of rigor of the previous OE responses was not initiated during the processing of IN 88-023, Supplement 5.

  The IN 88-023 action was created in September 1999, and assigned to an engineer for further evaluation and completion by January 2000. One due date extension was granted and the evaluation was competed during April 2000. In the evaluation, the engineer concluded that the SI system was susceptible to gas binding in the event of leakage from the SI accumulators through multiple check valves and/or motor operated valves. In addition, the engineer concluded that, "Frequent filling of an accumulator can be evidence of check valve leakage," and

"Small leakage over time can result in gas coming out of solution and voiding significant amounts of ECCS piping." The engineer recommended that another action item be created to address these concerns and listed specific areas to be addressed including:

- Addition of guidance to OI-100, "Adjusting SI Accumulator Level and Pressure," to check for ECCS piping voids when frequent accumulator filling was required
- Consideration of adding frequent venting of the ECCS piping upstream of the first and second off RCS check valves

Discussions between engineering and operations personnel concerning OI-100 procedure changes occurred between June 2000 and December 2001. At the beginning of December 2001, an action item was initiated to complete OI-100 revisions by March 8, 2002. The OI-100 revision had not been issued prior to the gas binding failure of 2P-15B on February 20, 2002.

In reviewing the corrective action program history of the in-depth re-evaluation of the gas binding phenomena for the single action item associated with IN 88-023, Supplement 5, the inspectors noted eight due date extensions encompassing 18 months (June 2000 to December 2001) before operations personnel agreed to the recommended OI-100 revisions and the revision date of March 8, 2002, was agreed upon. During the intervening 18 months, the inspectors noted deferral of OI-100 revisions for changes in system engineers, conflicts with a Unit 2 refueling outage, assignment of a new system engineer, further research on the feasibility of corrective actions, evaluation of the impact of improved TSs on the planned revision, and operations review of the recommended changes.

Pending further regulatory review, this issue will be carried under the URI opened in the 2002 Problem Identification and Resolution Inspection Report 50-266/02-03(DRP); 50-301/02-03(DRP) as URI 50-301/02-03-01.

Attachments 2: Draft NOV

NOTICE OF VIOLATION

Nuclear Management Company, LLC
Point Beach Nuclear Plant, Unit 2

Docket No. 050-00301
License No. DPR-27
EA-02-**XXX**

During an NRC inspection conducted on February 20 through March 31, 2002, a violation of NRC requirements was identified. In accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," NUREG-1600, the violation is listed below:

> Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B, requires, in part, that conditions adverse to quality be promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition.
>
> Contrary to the above, the licensee failed, on multiple occasions, to promptly identify and correct a significant condition adverse to quality regarding leakage from the 2T-34A safety injection accumulator. Specifically, on February 12, 2001, (CR 01-0454) and January 15, 2002, (AR 1862) licensed control room operators identified decreasing 2T-34A safety injection accumulator level trends but the license failed to determine the root cause of the leakage and prevent reoccurrence. In addition, NRC Information Notices 97-040 and 88-023, Supplements 1 through 5, provided at least six other corrective action program opportunities between 1989 and 1999 to cause the licensee to consider the effects of SI accumulator leakage on equipment operability. Failure of the licensee to critically evaluate and correct the cause of the accumulator leakage resulted in failure of the 2P-15B safety injection pump, due to gas binding caused by back-leakage of nitrogen-saturated water from the accumulator to the pump casing, on February 20, 2002, during monthly lubrication activities.

This violation is associated with a **WHITE ??** SDP finding.

Pursuant to the provisions of 10 CFR 2.201, Nuclear Management Company, LLC is hereby required to submit a written statement or explanation to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555 with a copy to the Regional Administrator, Region 3 and a copy to the NRC Resident Inspector at the facility that is the subject of this Notice, within 30 days of the date of the letter transmitting this Notice of Violation (Notice). This reply should be clearly marked as a "Reply to a Notice of Violation" and should include for each violation: (1) the reason for the violation, or, if contested, the basis for disputing the violation or severity level, (2) the corrective steps that have been taken and the results achieved, (3) the corrective steps that will be taken to avoid further violations, and (4) the date when full compliance will be achieved. Your response may reference or include previous docketed correspondence, if the correspondence adequately addresses the required response. If an adequate reply is not received within the time specified in this Notice, an order or a Demand for Information may be issued as to why the license should not be modified, suspended, or revoked, or why such other action as may be proper should not be taken.

~~***NOT FOR PUBLIC DISCLOSURE WITHOUT APPROVAL OF THE DIRECTOR, OE***~~

Where good cause is shown, consideration will be given to extending the response time.

If you contest this enforcement action, you should also provide a copy of your response, with the basis for your denial, to the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001.

Because your response will be made available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS), to the extent possible, it should not include any personal privacy, proprietary, or safeguards information so that it can be made available to the public without redaction. ADAMS is accessible from the NRC Web site at http://www.nrc.gov/NRC/ADAMS/index html (the Public Electronic Reading Room). If personal privacy or proprietary information is necessary to provide an acceptable response, then please provide a bracketed copy of your response that identifies the information that should be protected and a redacted copy of your response that deletes such information. If you request withholding of such material, you must specifically identify the portions of your response that you seek to have withheld and provide in detail the bases for your claim of withholding (e.g., explain why the disclosure of information will create an unwarranted invasion of personal privacy or provide the information required by 10 CFR 2.790(b) to support a request for withholding confidential commercial or financial information). If safeguards information is necessary to provide an acceptable response, please provide the level of protection described in 10 CFR 73.21.

In accordance with 10 CFR 19.11, you may be required to post this Notice within two working days.

Dated this ____ day of ______ 2002

Attachment 3 - SDP PHASE 1 SCREENING WORKSHEET FOR IE, MS, and B CORNERSTONES

Reference/Title: Point Beach Inspection Report 50-266/2002-003; 50-301/2002-003, Unresolved Item 50-301/02-03-01 and Point Beach Inspection Report 50-266/2002-005; 50-301/2002-005, Unresolved Item 50-301/02-03-01

Performance Deficiency (concise statement clearly stating the deficient licensee performance):
Licensee failed to critically evaluate and correct a significant condition adverse to quality regarding leakage from a safety injection accumulator that had been identified in two licensed reactor operator condition reports (January 2002 and February 2001) and six NRC generic communications (1988 through 2002). Failure of the licensee to critically evaluate and correct the cause of the accumulator leakage resulted in failure of the 2P-15B safety injection pump, due to gas binding caused by back-leakage of nitrogen-saturated water from the accumulator to the pump casing, on February 20, 2002, during monthly lubrication activities

Factual Description of Identified Condition (statement of <u>facts</u> known about the finding, without hypothetical failures included):
- Unit 2, 'B' Train SI pump, 2P-15B, failed on 2/20/02 during monthly preventative maintenance lubrication activities.
- 2P-15B failed within seconds of starting.
- inspection revealed damage to rotating element of pump, coupling and shaft keys between the pump and motor, the internal wearing rings, and inboard pump mechanical seal.
- gas binding in the 2P-15B pump casing caused the pump rotating element to seize to the internal pump wearing rings which caused damage to other components.
- 2P-15A, the Unit 2, 'A' Train SI pump was not affected by the gas binding that caused the failure of 2P-15B

System(s) and train(s) degraded by identified condition: Unit 2 'B' Train, high head safety injection

Licensing Basis Function of System(s) or Train(s):
The primary purpose of the safety injection system is to automatically deliver cooling water to the reactor core in the event of a LOCA. In the FSAR the safety injection pumps are relied upon to mitigate the consequences of the LBLOCA, SGTR, SBLOCA, and MSLB accidents. Relevant safety-related FSAR and other design basis functions include;
- deliver borated cooling water to the reactor cooling system (RCS) during the injection phase of SI to support core cooling
- increase the boron concentration in the RCS during the injection phase of SI to ensure adequate reactor shutdown margin in the event of a secondary pipe break
- recirculate and cool the water that is collected in the containment sump and return it to the RCS during the recirculation phase of SI to support long term cooling
- preclude containment leakage through the SI system piping penetrations following a loss of coolant accident to support the overall Containment function of limiting the release of potentially radioactive materials to the environment
- provide sufficient boron to maintain an adequate post-LOCA sump mean boron concentration to ensure shutdown of the core with all control rods out
- the SI system shall deliver borated water to the RCS, as necessary, to compensate for Xenon decay to maintain hot shutdown margin

Other Safety Function of System(s) or Train(s):
Relevant Non-Safety Related QA Functions (Augmented Qaulity)
- The SI system includes instrumentation which provides operator indication of SI system conditions during accident situations, as identified in the Wisconsin Electric commitment to Regulatory Guide 1.97.
- The SI system shall provide water from the refueling water storage tank to the chemical and volume control system following plant fires to accomplish the following safe shutdown functions (a) Reactivity control by injection of boron into the RCS; and (b) Reactor coolant makeup control by maintaining water inventory.

Maintenance Rule category (check one): _X_ risk-significant ___non-risk-significant

Time that identified condition existed or is assumed to have existed: One half time period between 1/24/02 at 0333 and 2/20/02 at 0100 or 16.97 days (17.0 days used in SDP) 2

Functions and Cornerstones degraded as a result of this identified condition (check □)

INITIATING EVENT CORNERSTONE

_____ Transient initiator contributor (e.g., reactor/turbine trip, loss offsite power)

_____ Primary or Secondary system LOCA initiator contributor (e.g., RCS or main steam/feedwater pipe degradations and leaks)

MITIGATION SYSTEMS CORNERSTONE

_____ Core Decay Heat Removal Degraded

__X__ Initial Injection Heat Removal Degraded

_____ Primary (e.g., Safety Inj)

_____ Low Pressure

__X__ High Pressure

_____ Secondary - PWR only (e.g., AFW)

_____ Long Term Heat Removal Degraded (e.g., ECCS sump recirculation, suppression pool cooling)

_____ Reactivity Control Degraded

_____ Fire/Flood/Seismic/Weather Protection Degraded

BARRIERS CORNERSTONE

_____ RCS LOCA Mitigation Boundary Degraded (e.g., PORV block valve, PTS issue)

_____ Containment Barrier Degraded

_____ Reactor Containment Degraded

_____ Actual Breach or Bypass

_____ Heat Removal, Hydrogen or Pressure Control Degraded

_____ Control Room, Aux Bldg, or Spent Fuel Bldg Barrier Degraded

_____ Fuel Cladding Barrier Degraded

SDP PHASE 1 SCREENING WORKSHEET FOR IE, MS, and B CORNERSTONES

Check the appropriate boxes □

If the finding is assumed to degrade:

1. fire protection defense in depth (DID), detection, suppression, barriers, fire brigade. **STOP. Go to** IMC 0609, Appendix F
2. the safety of a shutdown reactor. **STOP. Go to** IMC 0609, Appendix G
3. the safety of an operating reactor, identify the degraded areas:
   □ Initiating Event **XX** Mitigation Systems □ RCS Barrier □ Fuel Barrier □ Containment Barriers
4. **Two or more** of the above areas degraded □ **STOP. Go to Phase 2**
5. If **only one** of the above areas is degraded, continue **only** in the appropriate column below.

Initiating Event

1. Does the finding contribute to the likelihood of a Primary or Secondary system LOCA initiator?

☐ **If YES☐Stop. Go to Phase 2**

☐ If NO, continue

2. Does the finding contribute to both the likelihood of a reactor trip AND the likelihood that mitigation equipment or functions will not be available?

☐ **If YES☐Stop. Go to Phase 2**

☐ If NO, continue

3. Does the finding increase the likelihood of a fire or internal/external flood?

☐ **If YES** ☐ Use the IPEEE or other existing plant-specific analyses to identify core damage scenarios of concern and factors that increase the frequency. Provide this input for **Phase 3** analysis.

☐ If NO, screen as Green

Mitigation Systems

1. Is the finding a design or qualification deficiency confirmed not to result in loss of function per GL 91-18 (rev 1)?

☐ **If YES** ☐screen as Green

☐ If NO, continue

2. Does the finding represent an actual loss of safety function of a System?

☐ **If YES ☐Stop. Go to Phase 2**

☐ If NO, continue

3. Does the finding represent an actual loss of safety function of a single Train, for > its Tech Spec Allowed Outage Time?

XX **If YES ☐ Stop. Go to Phase 2**

☐ If NO, continue

4. Does the finding represent an actual loss of safety function of one or more non-Tech Spec Trains of equipment designated as risk-significant per 10CFR50.65, for >24 hrs?

☐ **If YES ☐ Stop. Go to Phase 2**

☐ If NO, continue

5. Does the finding screen as potentially risk significant due to a seismic, fire, flooding, or severe weather initiating event, using the criteria on page 3 of this Worksheet?

☐ **If YES** ☐ Use the IPEEE or other existing plant-specific analyses to identify core damage scenarios of concern and provide this input for **Phase 3** analysis.

☐ If NO, screen as Green

RCS Barrier or Fuel Barrier

1. RCS Barrier

Stop. Go to Phase 2

2. Fuel Barrier

screen as Green

Containment Barriers

1. Does the finding only represent a degradation of the radiological barrier function provided for the control room, or auxiliary building, or spent fuel pool, or SBGT system (BWR)?

☐ **If YES** ☐ screen as Green

☐ If NO, continue

2. Does the finding represent a degradation of the barrier function of the control room against smoke or a toxic atmosphere?

☐ **If YES ☐ Stop. Go to Phase 3**

☐ If NO, continue

3. Does the finding represent an actual open pathway in the physical integrity of reactor containment or an actual reduction of the atmospheric pressure control function of the reactor containment?

☐ **If YES ☐ Stop. Go to Appendix H of IMC 0609**

☐ If NO, screen as Green

SDP PHASE 1 SCREENING WORKSHEET FOR IE, MS, and B CORNERSTONES
Seismic, Fire, Flooding, and Severe Weather Screening Criteria

1. Does the finding involve the loss or degradation of equipment or function **specifically** designed to mitigate a seismic, flooding, or severe weather initiating event (e.g., seismic snubbers, flooding barriers, tornado doors)? (Equipment and functions for the mitigation or suppression of fire initiating events, such as thermal wrap or sprinkler systems, should be evaluated using IMC 0609 Appendix F and are not evaluated here)

   ☐**If YES** ☐ continue to question 2
   XX If NO ☐ skip to question 3

2. If the equipment or safety function is assumed to be completely failed or unavailable, are ANY of the following three statements TRUE? The loss of this equipment or function by itself, during the external initiating event it was intended to mitigate

   a) would cause a plant trip or any of the Initiating Events used by Phase 2 for the plant in question;

   b) would degrade **two or more** Trains of a multi-train safety system or function;

   c) would degrade one or more Trains of a system that supports a safety system or function.

   ☐**If YES** ☐ the finding is potentially risk significant due to external initiating event core damage sequences - return to page 2 of this Worksheet
   ☐ If NO, screen as Green

3. Does the finding involve the total loss of any safety function, identified by the licensee through a PRA, IPEEE, or similar analysis, that contributes to external event initiated core damage accident sequences (i.e., initiated by a seismic, fire, flooding, or severe weather event)?

   ☐**If YES** ☐ the finding is potentially risk significant due to external initiating event core damage sequences - return to page 2 of this Worksheet
   XX If NO, screen as Green

Result of Phase 1 screening process:

☐ **Screen as Green** XX **Go to Phase 2** ☐ **Go to Phase 3**

Important Assumptions (as applicable):
- 2P-15B was not recoverable
- last successful run of 2P-15B at 1/24/02 at 0333
- unpredictable behavior and variability of nitrogen leakage through SI pump mechanical seals and system valve packing leakage, as well as the existence of parallel leakage paths from the accumulator to the SI pump casing, require use of T/2 for determining exposure time.

Attachment 4: Point Beach Phase 2 SDP Worksheets

This section presents the Phase 2 SDP worksheets to used in the evaluation of the inspection finding for the Point Beach Nuclear Plant Unit 2 SI Pump failure. The SDP worksheets are presented for the following initiating event categories:

4. Transients (Reactor trip) (TRANS)
5. Transients without PCS (TPCS)
3. Loss of Single 125 V DC Bus 01 (LDC1)
4. Loss of Single 125 V DC Bus 02 (LDC2)
5. Small LOCA (SLOCA)
6. Stuck Open PORV (SORV)
7. Medium LOCA (MLOCA)
8. Loss of Offsite Power (LOOP)
9. LOOP Plus Loss of Gas Turbine with 1 EAC Bus Available (LEAC)
10. Steam Generator Tube Rupture (SGTR)
11. Main Steam Line Break (MSLB)

The remaining SDP worksheets did not require safety injection to mitigate the consequences of the particular accident and so, are not presented in this attachment:

1 Loss of CCW (LCCW)
2. Loss of Instrument Air (LOIA)
3. Loss of Service Water (LOSW)
4. Large LOCA (LLOCA)
5. Anticipated Transients Without Scram (ATWS)
6. Interfacing System LOCA (ISLOCA)

Table 3.1 SDP Worksheet for Point Beach Nuclear Plant, Units 1 and 2 — Transients (Reactor trip) (TRANS)

Estimated Frequency (Table 1 Row) __B_______ Exposure Time __17 Days__ Table 1 Result (circle): A B C D E F G H

Safety Functions Needed:	**Full Creditable Mitigation Capability for Each Safety Function:**
Power Conversion System (PCS)	½ Main Feedwater trains with ½ condensate trains (operator action = 3)
Secondary Heat Removal (AFW)	½ MDAFW trains (1 multi-train system) or 1 TDAFW train (1 ASD train)
Early Inventory, High Pressure Injection (EIHP)	½ HPSI pumps (1 multi-train system)
Primary Heat Removal, Feed/Bleed (FB)	½ PORVs and block valves open for Feed/Bleed (operator action = 2) (1)
High Pressure Recirculation (HPR)	½ HPSI pumps with ½ RHR pumps and ½ RHR heat exchangers with operator action for switchover (operator action = 2) (2)

Circle Affected Functions	**Recovery of Failed Train**	**Remaining Mitigation Capability Rating for Each Affected Sequence**	**Sequence Color**
1 TRANS - PCS - AFW - HPR (4)	0	TRANS(2) + PCS(3) + AFW(4) + HPR(2) = **11**	Green
2 TRANS - PCS - AFW - FB (5)			
3 TRANS - PCS - AFW - EIHP (6)	0	TRANS(2) + PCS(3) + AFW(4) + EIHP(2) = **11**	Green

Identify any operator recovery actions that are credited to directly restore the degraded equipment or initiating event None

Point Values:
Trans = 2 (Table 1, Row I 3-30 days)
PCS = 3 (Failure probability between 5E-4 and 5E-3)
AFW = 4 (2 Diverse Trains)
HPR = 2 (Failure probability between 5E-3 and 5E-2)
EIHP = 2 (Multi-train system reduced to single train system due to 2P-15B SI pump failure)

If operator actions are required to credit placing mitigation equipment in service or for recovery actions, such credit should be given only if the following criteria are met 1) sufficient time is available to implement these actions, 2) environmental conditions allow access where needed, 3) procedures exist, 4) training is conducted on the existing procedures under conditions similar to the scenario assumed, and 5) any equipment needed to complete these actions is available and ready for use

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Notes:

1. The human error probability (HEP) assessed in the IPE for establishing bleed and feed is approximately 2.0E-2
2. PBCH considers this action has an error probability of 1 3E-2 Here it is assigned a credit of 2, other W 2 Loop plants have a credit of 3.

Table 3.2 SDP Worksheet for Point Beach Nuclear Plant, Units 1 and 2 — Transients w/o PCS (TPCS)

Estimated Frequency (Table 1 Row) I **Exposure Time** 17 Days **Table 1 Result (circle): A B C D E F G H**

Safety Functions Needed:	**Full Creditable Mitigation Capability for Each Safety Function:**
Secondary Heat Removal (AFW)	½ MDAFW trains (1 multi-train system) or 1 TDAFW train (1 ASD train) with ½ SGs and associated 1/1 ADV or 1/4 SSVs
Early Inventory, High Pressure Injection (EIHP)	½ HPSI pumps (1 multi-train system)
Primary Heat Removal, Feed/Bleed (FB)	½ PORVs and block valves open for Feed/Bleed (operator action = 2) (1)
High Pressure Recirculation (HPR)	½ HPSI pumps with ½ RHR pumps with ½ RHR Heat Exchangers with operator action for switchover (operator action = 2) (2)

Circle Affected Functions	Recovery of Failed Train	Remaining Mitigation Capability Rating for Each Affected Sequence	Sequence Color
1 TPCS - AFW - HPR (3)	0	TPCS(2) + AFW(4) + HPR(2) = 8	Green
2 TPCS - AFW - FB (4)			
3 TPCS - AFW - EIHP (5)	0	TPCS(2) + AFW(4) + EIHP(2) = 8	Green

Identify any operator recovery actions that are credited to directly restore the degraded equipment or initiating event None

Point Values

TPCS = 2 (Table 1, Row I, 3-30 Days)
AFW = 4 (2 Diverse Trains)
HPR = 2 (Failure probability between 5E-3 and 5E-2)

If operator actions are required to credit placing mitigation equipment in service or for recovery actions, such credit should be given only if the following criteria are met 1) sufficient time is available to implement these actions, 2) environmental conditions allow access where needed, 3) procedures exist, 4) training is conducted on the existing procedures under conditions similar to the scenario assumed, and 5) any equipment needed to complete these actions is available and ready for use

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Notes:

1. The human error probability (HEP) assessed in the IPE for establishing bleed and feed is approximately 2 0E-2.
2. PBCH considers this action has an error probability of 1 3E-2 Here, it is assigned a credit of 2, other W 2 Loop plants has a credit of 3

Table 3.4 SDP Worksheet for Point Beach Nuclear Plant, Units 1 and 2 — Loss of Single 125V DC Bus 01 (LDC1)[1]

Estimated Frequency (Table 1 Row) __III____ Exposure Time __17 Days____ Table 1 Result (circle): A B C D E F G H

Safety Functions Needed:	**Full Creditable Mitigation Capability for Each Safety Function:**
Secondary Heat Removal (AFW)	1/1 MDAFW train (1 train) or 1 TDAFW train (1 ASD train) to ½ SGs with corresponding 1/1 ADV or 1/4 SSVs
Early Inventory, High Pressure Injection (EIHP)	1/1 HPSI pumps (1 train)
Primary Heat Removal, Feed/Bleed (FB)	1/1 PORVs and block valves open for Feed/Bleed (operator action = 2) [2]
High Pressure Recirculation (HPR)	1/1 HPSI pumps with 1/1 RHR pumps with operator action for switchover (operator action = 2)

Circle Affected Functions	**Recovery of Failed Train**	**Remaining Mitigation Capability Rating for Each Affected Sequence**	**Sequence Color**
1 LDC1 - AFW - HPR (3)	0	LDC1(4) + AFW(3) + HPR(0) = 7	Green
2 LDC1 - AFW - FB (4)			
3 LDC1 - AFW - EIHP (5)	0	LDC1(4) + AFW(3) + EIHP(0) = 7	Green

Identify any operator recovery actions that are credited to directly restore the degraded equipment or initiating event None
<u>Assumption</u>
Single low of 125VDC on 'A' train SI
<u>Point Values</u>
LDC1 = 4 (Table 1, Row III, 3-30 Days)
AFW = 3 (2 Diverse Train System reduced to multi train system due to loss of 'A' Train 125 VDC in this worksheet)
HPR = 0 (Loss of 125 VDC on 'A' Train, 2P-15B failure was on 'B' Train
EIHP = 0 (Loss of 125 VDC on 'A' Train, 2P-15B failure was on 'B' Train

If operator actions are required to credit placing mitigation equipment in service or for recovery actions, such credit should be given only if the following criteria are met 1) sufficient time is available to implement these actions, 2) environmental conditions allow access where needed, 3) procedures exist, 4) training is conducted on the existing procedures under conditions similar to the scenario assumed, and 5) any equipment needed to complete these actions is available and ready for use

<u>Notes:</u>
1. Loss of single 125V DC bus results in loss of control power to one set of emergency safety function equipment (i.e , 1 HPSI pump, 1 MDAFW pump, 1 RHR pump, etc) Also, control power to 1 PORV is lost. Loss of DC Bus 01 results in loss of control power for the main feedwater of the unit The IE frequency is estimated at ~9 3E-04/yr.
2. The human error probability (HEP) assessed in the IPE for establishing bleed and feed is approximately 2 0E-2
3. No separate event tree is drawn. Please refer to the Transients w/o PCS event tree.

Table 3.5 SDP Worksheet for Point Beach Nuclear Plant, Units 1 and 2 — Loss of Single 125 V DC Bus 02 (LDC2) (1)

Estimated Frequency (Table 1 Row) ____III_____ Exposure Time __17 Days_____ Table 1 Result (circle): A B C D E F G H

Safety Functions Needed:	**Full Creditable Mitigation Capability for Each Safety Function:**
Secondary Heat Removal (AFW)	1/1 MDAFW train (1 train) or 1 TDAFW train (1 ASD train) to 1/ 2 SGs with corresponding 1/1 ADV or 1/4 SSVs
Main Feedwater (MFW)	½ main feed pumps and ½ condensate pumps (operator action = 2)
Early Inventory, High Pressure Injection (EIHP)	1/1 HPSI pumps (1 train)
Primary Heat Removal, Feed/Bleed (FB)	1/1 PORVs and block valves open for Feed/Bleed (operator action = 2) (2)
High Pressure Recirculation (HPR)	1/1 HPSI pumps with 1/1 RHR pumps with operator action for switchover (operator action = 2)

Circle Affected Functions	Recovery of Failed Train	Remaining Mitigation Capability Rating for Each Affected Sequence	Sequence Color
1 LDC2 - AFW - MFW - HPR (4)	0	LDC2(4) + AFW(3) + MFW(2) + HPR(2) = 11	Green
2 LDC2 - AFW - MFW - FB (5)			
3 LDC2 - AFW - MFW - EIHP (6)	0	LDC2(4) + AFW(3) + MFW(2) + EIHP(2) = 11	Green

Identify any operator recovery actions that are credited to directly restore the degraded equipment or initiating event. None
Assumption
Loss of 125 VDC on 'B' SI and AFW train
Point Values
LDC2 = 4 (Table 1, Row III, 3-30 Days)
AFW = 3 (2 Diverse train system reduced to multi train system due to loss of 'B' train 125 VDC in this worksheet
MFW = 2 (Failure probability between 5E-3 and 5E-2)
HPR = 2 (Failure probability between 5E-3 and 5E-2)
EIHP = 2 (1 Train HPSI remaining)

If operator actions are required to credit placing mitigation equipment in service or for recovery actions, such credit should be given only if the following criteria are met 1) sufficient time is available to implement these actions, 2) environmental conditions allow access where needed, 3) procedures exist, 4) training is conducted on the existing procedures under conditions similar to the scenario assumed, and 5) any equipment needed to complete these actions is available and ready for use

Notes:

1 Loss of single 125V DC bus results in loss of control power to one set of emergency safety function equipment (i e , 1 HPSI pump, 1 MDAFW pump, 1 RHR pump, etc) Also, control power to 1 PORV is lost Loss of DC Bus 02 does not result in loss of control power for the main feedwater of the unit. The IE frequency is estimated at ~9 3E-04/yr
2 The human error probability (HEP) assessed in the IPE for establishing bleed and feed is approximately 2 0E-2
3 No separate event tree is drawn Please refer to the TRANS tree

Table 3.8 SDP Worksheet for Point Beach Nuclear Plant, Units 1 and 2 — Small LOCA (SLOCA)

Estimated Frequency (Table 1 Row) III **Exposure Time** 17 Days **Table 1 Result (circle): A B C D E F G H**

Safety Functions Needed:	**Full Creditable Mitigation Capability for Each Safety Function:**
Early Inventory, HP Injection (EIHP)	½ HPSI pumps (1 multi-train system)
Secondary Heat Removal (AFW)	½ MDAFW trains (1 multi-train system) or 1 TDAFW train (1 ASD train)
RCS Cooldown / Depressurization (RCSDEP)	Operator depressurizes RCS using pressurizer spray or ½ PORVs and atmospheric steam dump valves (operator action = 2) (2)
Primary Bleed (FB)	½ PORVs and block valves open for Feed/Bleed (operator action = 2) (1)
Accumulators (ACC)	½ Accumulators (1 multi-train system)
Low Pressure Injection (LPI)	½ RHR pumps (1 multi-train system)
Shutdown Cooling (SDC)	½ RHR pump trains in SDC mode (operator action = 2)
Low Pressure Recirculation (LPR)	½ RHR pumps taking suction from sump (operator action = 2)
High Pressure Recirculation (HPR)	½ HPSI pumps with ½ RHR pumps with ½ RHR Heat Exchangers with operator action for switchover (operator action = 2)

Circle Affected Functions	**Recovery of Failed Train**	**Remaining Mitigation Capability Rating for Each Affected Sequence**	**Sequence Color**
1 SLOCA - SDC (2)			
2 SLOCA - RCSDEP(2) - HPR (4)	0	SLOCA(4) + RCSDEP(2) + HPR(2) = 8	Green
3 SLOCA - AFW - HPR (6)	0	SLOCA(4) + AFW(4) + HPR(2) = 10	Green
4 SLOCA - AFW - FB (7)			
5 SLOCA - EIHP - LPR (9)	0	SLOCA(4) + EIHP(2) + LPR(3) = 9	Green
6 SLOCA - EIHP - LPI (10)	0	SLOCA(4) + EIHP(2) + LPI(3) = 9	Green

7 SLOCA - EIHP - ACC (11)	0	SLOCA(4) + EIHP(2) + ACC(3) = 9	Green
8 SLOCA - EIHP - RCSDEP[2] (12)	0	SLOCA(4) + EIHP(2) + RCSDEP(2) = 8	
9 SLOCA - EIHP - AFW (13)	0	SLOCA(4) + EIHP(2) + AFW(4) = 10	Green

Identify any operator recovery actions that are credited to directly restore the degraded equipment or initiating event None

Point Values
SLOCA = 4 (Table 1, Row III, 3-30 Days)
RCSDEP= 2 (Failure probability between 5E-3 and 5E-2)
HPR=2 ((Failure probability between 5E-3 and 5E-2, 2P-15B failure occurred on 'B' train SI, 'A' train RHR & SI still available)
AFW=4 (2 diverse trains)
EIHP = 2 (2P-15B unavailable, 1 train system with 'A' train left)
LPI = 3 (Multi train system)
ACC = 3 (Multi train system)

If operator actions are required to credit placing mitigation equipment in service or for recovery actions, such credit should be given only if the following criteria are met 1) sufficient time is available to implement these actions, 2) environmental conditions allow access where needed, 3) procedures exist, 4) training is conducted on the existing procedures under conditions similar to the scenario assumed, and 5) any equipment needed to complete these actions is available and ready for use

Notes:
1. The human error probability (HEP) assessed in the IPE for establishing bleed and feed cooling is approximately 2 0E-2
2. Sequence 2 is a controlled cooldown and Sequence 8 is a rapid depressurization PBCH estimates the error probability for operator failure to cooldown following SLOCA is 2 7E-3, and the operator failure to depressurize for LPI injection is 1 2E-2 Here, this function is assigned a credit of 2

Table 3.9 SDP Worksheet for Point Beach Nuclear Plant, Units 1 and 2 — Stuck Open PORV (SORV)

Estimated Frequency (Table 1 Row) III Exposure Time 17 Days Table 1 Result (circle): A B C D E F G H

Safety Functions Needed:	Full Creditable Mitigation Capability for Each Safety Function:
Early Inventory, HP Injection (EIHP)	½ HPSI pumps (1 multi-train system)
Isolation of Small LOCA (BLK)	The closure of the block valve associated with stuck open PORV (operator action = 1)
Secondary Heat Removal (AFW)	½ MDAFW trains (1 multi-train system) or 1 TDAFW train (1 ASD train)
RCS Cooldown / Depressurization (RCSDEP)	Operator depressurizes RCS using pressurizer sprays and ½ PORVs and block valves or atmospheric dump valves (operator action = 2)
Primary Heat Removal, Feed & Bleed (FB)	Operator action using stuck-open PORV (operator action = 2) (1)
Accumulators (ACC)	½ Accumulators (1 multi-train system)
Low Pressure Injection (LPI)	½ RHR pumps (1 multi-train system)
High Pressure Recirculation (HPR)	½ HPSI pumps with ½ RHR pumps and ½ RHR Heat exchangers with operator action for switchover (operator action = 1)
Low Pressure Recirculation (LPR)	½ RHR pumps taking suction from the sump (operator action = 2)
Shutdown Cooling (SDC)	½ RHR pumps in SDC mode (operator action = 2)

Circle Affected Functions	Recovery of Failed Train	Remaining Mitigation Capability Rating for Each Affected Sequence	Sequence Color
1 SORV - BLK - SDC (2)			
2 SORV - BLK - RCSDEP(2) -HPR (4)	0	SORV(4) + BLK(1) + RCSDEP(2) + HPR(2) = 9	Green
3 SORV - BLK - AFW - HPR (6)	0	SORV(4) + BLK(1) + AFW(4) + HPR(2) = 11	Green
4 SORV - BLK - AFW - FB (7)			

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5 SORV - BLK - EIHP - LPR (9)	0	SORV(4) + BLK(1) + EIHP(2) + LPR(2) = 9	Green
6 SORV - BLK - EIHP - LPI (10)	0	SORV(4) + BLK(1) +EIHP(2) + LPI(3) = 10	Green
7 SORV - BLK - EIHP - ACC (11)	0	SORV(4) +BLK(1) + EIHP(2) + ACC(3) = 10	Green
8 SORV - BLK - EIHP - RCSDEP(2) (12)	0	SORV(4) + BLK(1) + EIHP(2) + RCSDEP(2) = 9	Green
9 SORV - BLK - EIHP - AFW (13)	0	SORV(4) + BLK(1) + EIHP(2) + AFW(4) =11	Green

Identify any operator recovery actions that are credited to directly restore the degraded equipment or initiating event: None

Point Values
SORV=4 (Table 1, Row III, 3-30 Days)
BLK=1 (Operator action, failure probability between5E-2 and 0.5)
RCSDEP= 2 (Operator action, 5E-3 and 5E-2)
HPR=2 (Operator action, 5E-3 and 5E-2)
AFW =4 (2 Diverse trains)
EIHP= 2 (Multi train system reduced to single train system)
LPI=3 (Multi train system)
ACC=3 (Multi train system)

If operator actions are required to credit placing mitigation equipment in service or for recovery actions, such credit should be given only if the following criteria are met: 1) sufficient time is available to implement these actions, 2) environmental conditions allow access where needed, 3) procedures exist, 4) training is conducted on the existing procedures under conditions similar to the scenario assumed, and 5) any equipment needed to complete these actions is available and ready for use.

Notes:
1. The human error probability (HEP) assessed in the IPE for establishing bleed and feed cooling is approximately 2 0E-2
2. Sequence 2 is a controlled cooldown and Sequence 8 is a rapid depressurization. PBCH estimates the error probability for operator failure to cooldown following SLOCA is 2.7E-3, and the operator failure to depressurize for LPI injection is 1.2E-2 Here, this function is assigned a credit of 2.
3. No separate event tree is provided Please refer to the SLOCA tree.

Table 3.10 SDP Worksheet for Point Beach Nuclear Plant, Units 1 and 2 — Medium LOCA (MLOCA)

Estimated Frequency (Table 1 Row) __III______ **Exposure Time** __17 Days________ **Table 1 Result (circle): A B C D E F G H**

Safety Functions Needed:	Full Creditable Mitigation Capability for Each Safety Function:
Early Inventory, HP Injection (EIHP)	½ HPSI pumps (1 multi-train system)
Auxiliary Feedwater (AFW)	½ MDAFW pumps (1 multi-train system) or 1/1 TDAFW pumps (1 ASD train)
RCS Depressurization (DEP)	Operator depressurizes using ½ atmospheric dump valves (operator action = 2)
Accumulator (ACC)	1/1 ACC injection to 1 intact loop (1 train) [1]
Low Pressure Injection (LPI)	½ RHR pumps (1 multi-train system)
High Pressure Recirculation (HPR)	½ HPSI pumps taking suction from ½ RHR pumps with operator action for switchover (operator action = 2)
Low Pressure Recirculation (LPR)	½ RHR pump trains with operator switchover from injection to recirculation (operator action = 2)

Circle Affected Functions	Recovery of Failed Train	Remaining Mitigation Capability Rating for Each Affected Sequence	Sequence Color
1 MLOCA - HPR (2)	0	MLOCA(4) + HPR(2) = 6	White
2 MLOCA - ACC (3,7)			
3 MLOCA - EIHP - LPR (5)	0	MLOCA(4) + EIHP(2) + LPR(2) = 8	Green
4 MLOCA - EIHP - LPI (6)	0	MLOCA(4) + EIHP(2) + LPI(3) = 9	Green
5 MLOCA - EIHP - DEP (8)	0	MLOCA(4) + EIHP(2) + DEP(2) = 8	Green

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6 MLOCA - EIHP - AFW (9)	0	MLOCA(4) + EIHP(2) + AFW(4) = 10	Green

Identify any operator recovery actions that are credited to directly restore the degraded equipment or initiating event None

Point Values

MLOCA = 4 (Table 1, Row III, 3-30 Days)
HPR =2 (Operator action, failure probability between 5E-3 and 5E-2)
EIHP = 2 (Multi train system reduced to single train system)
LPR = 2 (Operator action, failure probability between 5E-3 and 5E-2)
LPI = 3 (Multi train system)
DEP = 2 (Operator action, failure probability between 5E-3 and 5E-2)
AFW = 4 (2 Diverse trains)

If operator actions are required to credit placing mitigation equipment in service or for recovery actions, such credit should be given only if the following criteria are met 1) sufficient time is available to implement these actions, 2) environmental conditions allow access where needed, 3) procedures exist, 4) training is conducted on the existing procedures under conditions similar to the scenario assumed, and 5) any equipment needed to complete these actions is available and ready for use

Note

1 The medium LOCA is considered to be 3 inches in diameter. The RCS will not immediately depressurize below the accumulator discharge pressure HPSI pumps will maintain water inventory to insure adequate core cooling, the assumption that accumulators are necessary is conservative

Table 3.12 SDP Worksheet for Point Beach Nuclear Plant, Units 1 and 2 — Loss of Offsite Power (LOOP)

Estimated Frequency (Table 1 Row) ____II____ Exposure Time 17 Days ________ Table 1 Result (circle): A B C D E F G H

Safety Functions Needed:	**Full Creditable Mitigation Capability for Each Safety Function:**
Emergency AC Power (EAC)	½ dedicated Emergency Diesel Generators [1] (1 multi-train system) or crosstie opposite unit EDG (operator action = 1) or 1/1 Gas Turbine (operator action = 1) [1]
Turbine-driven AFW Pump (TDAFW)	1/1 TDP trains of AFW (1 ASD train)
Secondary Heat Removal (AFW)	½ MDAFW trains (1 multi-train system) or 1/1 TDAFW train (1 ASD train)
Motor-driven AFW Pumps (MDAFW)	½ MDAFW trains (1 multi-train system)
Recovery of AC Power in < 1 hr (REC1)	SBO procedures implemented (operator action = 1) [1]
Recovery of AC Power in 2-7 hrs (REC7)	SBO procedures implemented (operator action = 1) [2]
Early Inventory, HP Injection (EIHP)	½ HPSI pumps (1 multi-train system)
Primary Heat Removal (FB)	Operator uses RCS pressurizer ½ PORVs and block valves (operator action = 2)
High Pressure Recirculation (HPR)	½ HPSI pumps with ½ RHR pumps and with operator action for switchover (operator action = 2)

Circle Affected Functions	**Recovery of Failed Train**	**Remaining Mitigation Capability Rating for Each Affected Sequence**	**Sequence Color**
1 LOOP - AFW - HPR (3)	0	LOOP(3) + AFW(4) + HPR(2) = 9	Green
2 LOOP - AFW - FB (4)			
3 LOOP - AFW - EIHP (5)	0	LOOP(3) + AFW(4) + EIHP(2) = 9	Green
4 LOOP - EAC - TDAFW - HPR (9, 11) (AC recovered)	0	LOOP(3) + EAC(5) + TDAFW(1) + HPR(2) = 11	Green

5 LOOP - EAC -TDAFW - MDAFW - EIHP (13) (AC recovered)	0	LOOP(3) + EAC(5) + TDAFW(1) + MDAFW(3) +EIHP(2) = 14	Green
6 LOOP - EAC - REC7 (7)			
7 LOOP - EAC - TDAFW - MDAFW - FB (12) (AC recovered)			
8 LOOP - EAC - TDAFW - REC1 (14)			

Identify any operator recovery actions that are credited to directly restore the degraded equipment or initiating event None

Point Values

LOOP = 3 (Table 1, Row II, 3-30 Days)
AFW = 4 (2 Diverse Trains)
HPR = 2 (Operator action, failure probability between 5E-3 and 5E-2)
EIHP = 2 (Multi train system reduced to single train system)
EAC = 5 ([One multi train system (3) and crosstie EDG's, operator action (1) and gas turbine, operator action (1)]
TDAFW = 1 (Automatic steam-driven train)
MDAFW = 3 (Multi train system)

If operator actions are required to credit placing mitigation equipment in service or for recovery actions, such credit should be given only if the following criteria are met. 1) sufficient time is available to implement these actions, 2) environmental conditions allow access where needed, 3) procedures exist, 4) training is conducted on the existing procedures under conditions similar to the scenario assumed, and 5) any equipment needed to complete these actions is available and ready for use

Notes:

1 Each PBCH unit has two trains with one diesel normally aligned to each units train (1 diesel to each of 4 trains) In our modeling, dual unit LOOP is assumed On a dual unit LOOP, each diesel would start and load to their respective train (ie, 2 diesels per unit, 1 on each train) However, if a diesel failed, the opposite unit's diesel could be aligned to handle both units on the same train This requires a manual action with an HEP of around 3E-2 Operator action = 1 is assigned based on generic assignment of credit for such actions Upon a loss of offsite power and the EDGs, operator will attempt to start and align the GTG. The HEP for starting and aligning the GTG is 1.3E-01 and a credit of 1 is assigned

2. For the functions "Recovery of AC Power in < 1 hrs (REC1)" and "Recovery of AC Power in 2-7 hrs (REC7)" the corresponding estimated probabilities in the IPE are 4E-1 and 2 8E-1 to 4 0E-2. Both the actions are given a credit of 1.

3 Battery depletion in about 1 hour. Power must be restored within approximately 2 hours if the RCS cooldown was not successful and the TDAFW

pump runs for only 1 hour, i e , until battery depletion Power must be restored within 4 hours if the RCS cooldown was successful resulting in a 2 hours or more benefit in core uncovery at low RCP seal leakage rate Recovery within 7 hour applies assuming TDAFW pump operation until 4 hours, implying local "blind" operation of the pump without the benefit of instrumentation following battery depletion

Table 3.13 SDP Worksheet for Point Beach Nuclear Plant, Units 1 and 2 — LOOP Plus Loss of Gas Turbine with 1 EAC Available (LEAC)[1]

Estimated Frequency (Table 1 Row) ___V_____ Exposure Time ___17 Days_____ Table 1 Result (circle): A B C D E F G H

Safety Functions Needed:	Full Creditable Mitigation Capability for Each Safety Function:
Secondary Heat Removal (AFW)	1/1 MDAFW trains (1 train)
Relief Valves Reclosing (SORV)	All relief valves reclose (1 train)
Early Inventory, High Pressure Injection (EIHP)	1/1 HPSI pumps (1 train)
Primary Heat Removal, Feed / Bleed (FB)	1/1 PORVs and block valves open for Feed/Bleed (operator action = 2) [1]
RCS Cooldown / Depressurization (RCSDEP)	Operator depressurizes RCS using pressurizer sprays and 1/1 PORVs and block valves or atmospheric dump valves (operator action = 2)
Low Pressure Recirculation (LPR)	1/ 2 RHR pumps taking suction from the sump (operator action = 2)
High Pressure Recirculation (HPR)	1/1 HPSI pumps with 1/1 RHR pumps (requires operator action for switchover; operator action = 2)

Circle Affected Functions	Recovery of Failed Train	Remaining Mitigation Capability Rating for Each Affected Sequence	Sequence Color
1 LEAC - AFW - HPR (3)	0	LEAC(6) + AFW(3) + HPR(0) = 9	Green
2 LEAC - AFW - FB (4)			
3 LEAC - AFW - EIHP (5)	0	LEAC(6) + AFW(3) + EIHP(0) = 9	Green
4 LEAC - SORV - LPR (7)			

5 LEAC - SORV - RCSDEP - HPR (9)	0	LEAC(6) + SORV(2) + RCSDEP(2) = 10	Green
6 LEAC - SORV - EIHP (10)	0	LEAC(6) +SORV(2) + EIHP(0) = 8	Green

Identify any operator recovery actions that are credited to directly restore the degraded equipment or initiating event:
<u>Assumption</u>
Emergency power unavailable for 'A' SI train
<u>Point Values:</u>
LEAC = 6 (Table 1, Row V, 3-30 Days)
AFW = 3 (One MDAFW pump available (1 train = 2) and one TDAFW (1 automatic steam-driven train = 1)
HPR = 0 (2P-15B for 'B' train SI, EAC failure occurs on 'A' train SI)
EIHP = 0 (2P-15B for 'B' train SI, EAC failure occurs on 'A' train SI)
SORV = 2 (1 train)
RCSDEP= 2 (Operator action, failure probability between 53-3 and 5E-2)

If operator actions are required to credit placing mitigation equipment in service or for recovery actions, such credit should be given only if the following criteria are met: 1) sufficient time is available to implement these actions, 2) environmental conditions allow access where needed, 3) procedures exist, 4) training is conducted on the existing procedures under conditions similar to the scenario assumed, and 5) any equipment needed to complete these actions is available and ready for use.

<u>Note</u>:
1 Upon LOOP and failure of one EDG, the Gas Turbine Generator will be started whereby the train with unfailed equipment but no power will also be started In such situations, the accident scenarios will be the same as that in the previous worksheet. This worksheet focuses on the situation where with failure of 1 EAC, the Gas Turbine generator has failed to start reducing the redundancy of the safety systems as defined above

Table 3.14 SDP Worksheet for Point Beach Nuclear Plant, Units 1 and 2 — Steam Generator Tube Rupture (SGTR)

Estimated Frequency (Table 1 Row) ___III___ Exposure Time _17 Days_______ Table 1 Result (circle): A B C _D_ E F G H

Safety Functions Needed:	Full Creditable Mitigation Capability for Each Safety Function:
Secondary Heat Removal (AFW)	1/2 MDAFW trains (1 multi-train system) or 1/1 TD AFW train (1 ASD Train)
Early Inventory, HP Injection (EIHP)	1/2 HPSI pumps (1 multi-train system)
Main Feedwater (MFW)	1/2 MFW pumps with 1/2 condensate pumps [1] (operator action = 2)
SG Isolation (SGI)	Operator isolates the ruptured SG (operator action = 2) [2]
Pressure Equalization (EQ)	Operator cools down RCS using 1/1 SG ADV (on each SG fed by AFW) or 1/2 RCS pressurizer PORVs to less than setpoint of relief valves of SG (operator action = 2) [3]
Decay Heat Removal (DHR)	Cooldown and depressurize primary and align 1/2 RHR pumps (operator action = 2)

Circle Affected Functions	Recovery of Failed Train	Remaining Mitigation Capability Rating for Each Affected Sequence	Sequence Color
1 SGTR - EQ - DHR (3, 8)			
2 SGTR - SGI - DHR (5,10)			
3 SGTR - AFW - EQ (12)			
3 SGTR - AFW - SGI (13)			
4 SGTR - AFW - EIHP (14)	0	SGTR(4) + AFW(4) + EIHP(2) = 10	Green
5 SGTR - AFW - MFW (15)			

Identify any operator recovery actions that are credited to directly restore the degraded equipment or initiating event: None

<u>Point Values:</u>

SGTR = 4 (Table 1, Row III, 3-30 Days)
AFW = 4 (2 Diverse trains)
EIHP = 2 (Multi train system reduced to single train system)

If operator actions are required to credit placing mitigation equipment in service or for recovery actions, such credit should be given only if the following criteria are met: 1) sufficient time is available to implement these actions, 2) environmental conditions allow access where needed, 3) procedures exist, 4) training is conducted on the existing procedures under conditions similar to the scenario assumed, and 5) any equipment needed to complete these actions is available and ready for use

<u>Notes</u>:

1. Point Beach SGTR analysis credits the recovery of main feedwater if auxiliary feedwater fails, but does not credit the use of feed and bleed if all feedwater fails.
2. Failure to identify and isolate a ruptured SG is assigned an error probability of 4 8E-3 Failure to isolate ruptured SG and stop TDAFW flow is assigned an error probability of 8 5E-03 in the IPE.
3. Failure to cooldown and depressurize for SGTR is assigned a failure probability of 2 0E-02

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Table 3.15 SDP Worksheet for Point Beach Nuclear Plant, Units 1 and 2 — Main Steam Line Break (MSLB)[1]

Estimated Frequency (Table 1 Row) __ III __ Exposure Time __ 17 Days __ Table 1 Result (circle): A B C D E F G H

Safety Functions Needed:	Full Creditable Mitigation Capability for Each Safety Function:
Early Inventory, HP Injection (EIHP)	1/2 HPSI pumps (1 multi-train system)
Secondary Heat Removal (AFW)	1/2 MD AFW trains (1 multi-train system) or 1/1 TDAFW train (1 ASD Train)
Main Steam Isolation (ISOL)	Automatic signal for MSIV closure and operator verification (1 train)
Primary Heat Removal, Feed and Bleed (FB)	1/2 PORVs with block valves open (operator action = 2)
High Pressure Recirculation (HPR)	1/2 HPSI pumps taking suction from 1/2 RHR pumps with operator action for switchover (operator action = 2)

Circle Affected Functions	Recovery of Failed Train	Remaining Mitigation Capability Rating for Each Affected Sequence	Sequence Color
1 MSLB - AFW - HPR (3)	0	MSLB(4) + AFW(4) + HPR(2) = 10	Green
2 MSLB - AFW - FB (4)			
3 MSLB - ISOL - HPR (6)	0	MSLB(4) + ISOL(2) + HPR(2) = 8	Green
4 MSLB - ISOL - FB (7)			
5 MSLB - EIHP - AFW (9)	0	MSLB(4) + EIHP(2) + AFW(4) = 10	Green

6 MSLB - EIHP - ISOL (10)	**0**	**MSLB(4) + EIHP(2) + ISOL(4) = 10**	**Green**

Identify any operator recovery actions that are credited to directly restore the degraded equipment or initiating event: None
<u>Point Values</u>
MSLB= 4 (Table 1, Row III, 3-30 Days)
AFW = 4 (2 Diverse trains)
HPR = 2 (Operator action, failure probability between 53-3 and 5E-2)
ISOL = 2 (1 Train)
EIHP= 2 (Operator action, failure probability between 53-3 and 5E-2)

If operator actions are required to credit placing mitigation equipment in service or for recovery actions, such credit should be given only if the following criteria are met: 1) sufficient time is available to implement these actions, 2) environmental conditions allow access where needed, 3) procedures exist, 4) training is conducted on the existing procedures under conditions similar to the scenario assumed, and 5) any equipment needed to complete these actions is available and ready for use

<u>Note</u>:
1 PBNS models assume break inside containment

Attachment 5 - Counting Rule Worksheet

Application of SDP Counting Rule
Based on the counting rules of the SDP discussed in Inspection Manual Chapter 0609, Appendix A, Attachment 2, paragraph 3.2; every 3 affected accident sequences that have the same order of magnitude of risk, as determined by the addition of the initiating event likelihood and the remaining mitigation capability, constitute one equivalent sequence which is more risk significant by one order of magnitude. This rule is applied in a cascading fashion.

For instance, nine sequences of 10^{-9} would equal three sequences of 10^{-8}. Ten sequences of 10^{-8} would equal 3 sequences of 10^{-7}. The table below provides the results of the roll-up of the event sequences provided in the SDP/ENFORCEMENT PANEL WORKSHEET. The application of the counting rule results in an inspection finding of at least substantial safety significance (YELLOW). Using the Counting Rule Worksheet from 0609, Appendix A, Attachment 1, Table 6;

Counting Rule Worksheet

Step	Instructions	
(1)	Enter the number of sequences with a risk significance equal to 9	(1) 9
(2)	Divide the result of Step (1) by 3 and round down	(2) 3
(3)	Enter the number of sequences with a risk significance equal to 8	(3) 9
(4)	Add the result of Step (3) to the result of Step (2)	(4) 12
(5)	Divide the result of Step (4) by 3 and round down	(5) 4
(6)	Enter the number of sequences with a risk significance equal to 7.	(6) 2
(7)	Add the result of Step (6) to the result of Step (5).	(7) 6
(8)	Divide the result of Step (7) by 3 and round down	(8) 2
(9)	Enter the number of sequences with a risk significance equal to 6.	(9) 1
(10)	Add the result of Step (9) to the result of Step (8).	(10) 3
(11)	Divide the result of Step (10) by 3 and round down.	(11) 1
(12)	Enter the number of sequences with a risk significance equal to 5.	(12) 0
(13)	Add the result of Step (12) to the result of Step (11).	(13) 1
(14)	Divide the result of Step (13) by 3 and round down.	(14) 0
(15)	Enter the number of sequences with a risk significance equal to 4.	(15) 0
(16)	Add the result of Step (15) to the result of Step (14).	(16) 0

- If the result of Step 16 is greater than zero, then the risk significance of the inspection finding is of high safety significance (RED).
- If the result of Step 13 is greater than zero, then the risk significance of the inspection finding is at least of substantial safety significance (YELLOW).
- If the result of Step 10 is greater than zero, then the risk significance of the inspection finding is at least of low to moderate safety significance (WHITE).
- If the result of Steps 10, 13, and 16 are zero, then the risk significance of the inspection finding is of very low safety significance (GREEN)

Phase 2 Result: ☐ **GREEN** ☐ **WHITE** **XX YELLOW** ☐ **RED**